CHAPTER 10. NATIONAL IMPACT ANALYSIS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 10. NATIONAL IMPACT ANALYSIS

10.1 INTRODUCTION

The Energy Policy and Conservation Act (EPCA) states that any new or amended standard must be chosen so as to achieve the maximum improvement in energy efficiency that is technologically feasible and economically justified. In determining whether economic justification exists, the Department of Energy (DOE) must determine whether the benefits of the candidate standard level exceed its burdens. Key factors in this decision are: the total projected amount of energy savings likely to result directly from the imposition of the standard, and the savings in operating costs throughout the life of the covered equipment in the type (or class) compared to any increase in the price of, or in the initial charges for or maintenance expenses of, the covered equipment that are likely to result from the promulgation of the standard.

To satisfy this EPCA requirement and to more fully understand the national impact of potential efficiency regulations for distribution transformers, DOE conducted a national impact analysis (NIA). This analysis assessed future national energy savings (NES) from transformer energy conservation standards and the national economic impact using the net present value (NPV) metric.

This chapter describes the method used to estimate the national impacts of candidate standard levels (CSLs) for medium voltage liquid-immersed and low and medium voltage dry-type distribution transformers; these transformers have been categorized into ten distinct equipment classes. DOE evaluated the following impacts: (1) NES attributable to each possible standard, (2) monetary value of those energy savings to consumers of the considered equipment, (3) increased total installed cost of the equipment because of standards, and (4) NPV of energy savings (the difference between the operational savings and increased total installed cost).

To conduct its NIA, DOE determined both the NES and NPV for each of the efficiency levels being considered as the new standard for distribution transformers. DOE performed all calculations for each considered equipment class using a Microsoft Excel spreadsheet model, which is accessible on the Internet. <www.eere.energy.gov/buildings/appliance_standards/> The spreadsheets combine the calculations for determining the NES and NPV for each considered equipment class with input from the appropriate shipments model that DOE used to forecast future purchases of the considered equipment. Chapter 9 provides a detailed description of the shipments models, including detailed descriptions of consumers' sensitivities to total installed cost, operating cost, and income, and how DOE captured those sensitivities within the model.

The NES and NPV together constitute the NIA model. Details and instructions for using the NIA model are provided in appendix 10-A.

To estimate the national impacts of new standards for all the equipment classes considered in this rulemaking, DOE used a rescaling factor (described in Section 10.2.2.1) to allocate the equipment cost and annual energy consumption of each representative size equipment to all sizes classes within the equipment class.

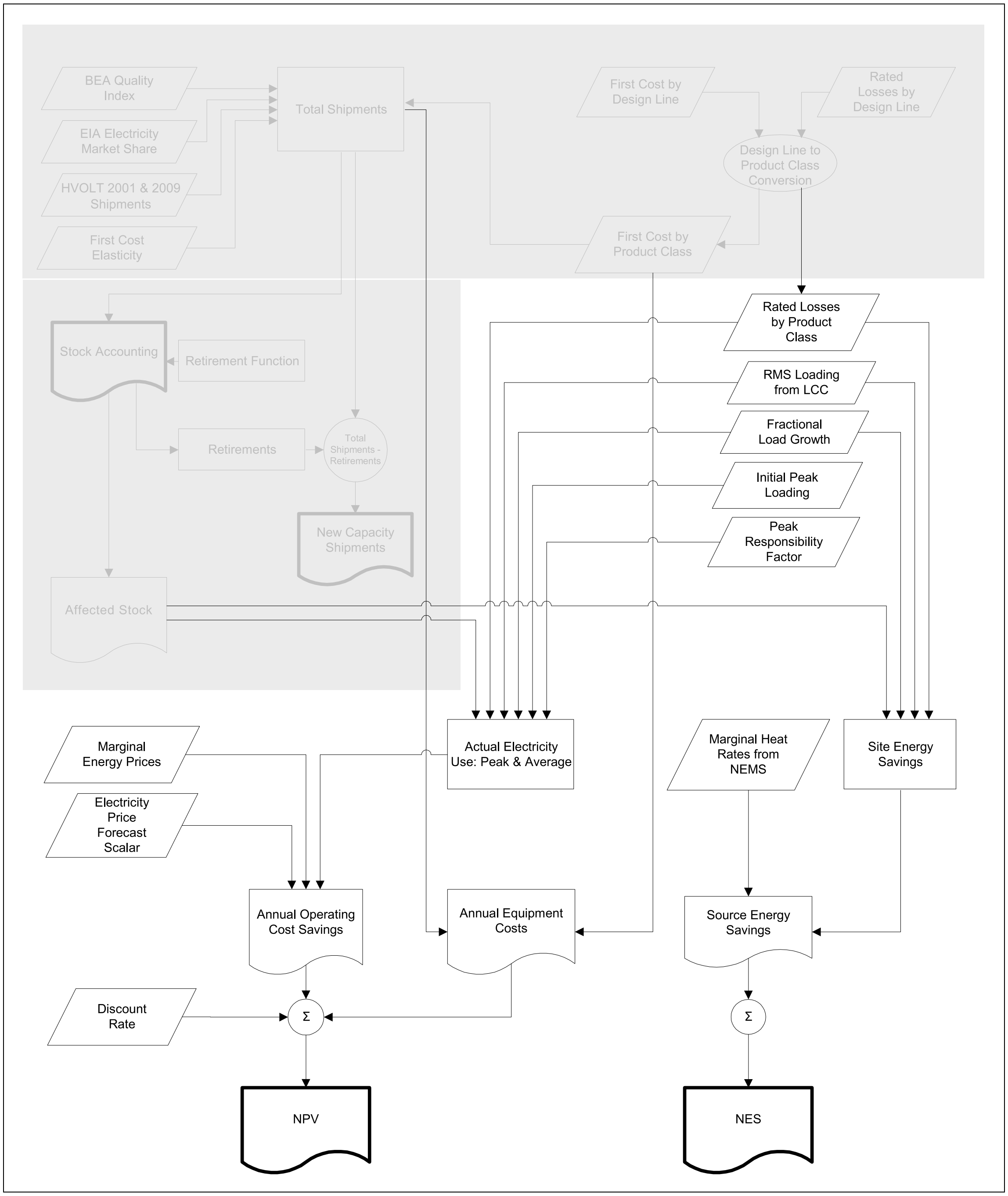

Figure 10.1.1 National Impact Analysis Spreadsheet Flowchart

Figure 10.1.1 presents a graphical flow diagram of the distribution transformer NIA (NES and NPV) model and spreadsheet. In the diagram, the arrows show the direction of information flow for the calculation. The information begins with inputs (shown as parallelograms). As information flows from these inputs, it may be integrated into intermediate results (shown as rectangles) or through integrating sums or differences (shown as circles) into major outputs (shown as boxes with curved bottom edges). Note that the shipments model portion of the flow diagram (shaded) is discussed in Chapter 9.

The NIA calculation started with the shipments model. This model integrated the inputs of 2001 shipments estimates from DOE's contractor[1], the U.S. Bureau of Economic Analysis (BEA) transformer quantity index[2], electricity market shares from DOE's Energy Information Administration (EIA)[3,4] and equipment price estimates from DOE's life-cycle cost (LCC) analysis. The model produced a backcast and a forecast of total shipments. DOE used the total shipments and a retirement function to produce an accounting of in-service transformers (stocks), enabling DOE to estimate the stock that is affected by trial standards and transformer retirements.

After the shipments calculation, the NES and NPV calculations begin. For both calculations key inputs from the LCC analysis are the average rated no-load and load losses and the cost of transformers, including installation. DOE adjusted the losses and the equipment costs for transformer size and equipment class to convert the data from representative design lines to average equipment class information. Additional inputs on average and peak losses—including root mean square (RMS) loading, peak loading, and peak responsibility factor—allowed DOE to convert rated losses into actual losses. At this point, the information flow for the NES and NPV calculation split into two paths.

On one path, the NES calculation sums the watt-hours of energy consumed by the affected stock, taking the difference between the base case and standards scenario to calculate site energy savings. DOE converted these site energy savings to energy savings at the source (i.e., at the power plant), using average heat rates for base load and peak load generation from the National Energy Modeling System (NEMS)[5]. The average heat rates from NEMS include the transmission and distribution losses. Summing the annual energy savings for the forecast period, which extends from 2016 through 2045, provides the final NES result.

On the other path, the NPV calculation starts with marginal price inputs from the LCC analysis for both energy costs and capacity costs and for both load losses and no-load losses. The marginal prices, when combined with the actual peak and average losses, provide the estimate of the operating cost. Meanwhile, the adjusted equipment installed cost times the annual shipments provides the estimate of the total annual equipment costs. DOE calculated three differences to assess the net impact of each candidate standard level (CSL). The first difference was between the candidate standards scenario equipment costs and the base case equipment costs to obtain the net equipment cost increase from a candidate standard. The second difference was between the base case scenario operating cost and the candidate standards scenario operating cost to obtain the net operating cost savings from a candidate standard. The third difference was between the net operating cost savings and the net equipment cost increase to get the net expense or savings for each year. DOE then discounted the net expenses or savings to 2010 and summed them over the years 2016–2104[a] for transformers purchased during 2016-2045 to provide the NPV impact of a candidate standard.

Two models included in the NIA are provided below—the NES model in section 10.2, and the NPV model in section 10.3. Each technical description begins with a summary of the model. It then provides a descriptive overview of how DOE performed each model's calculations and follows with a summary of the inputs. The final subsections of each technical description describe each of the major inputs and computation steps in detail and with equations, when appropriate. After the technical model descriptions, this chapter presents the results of the NIA calculations.

10.2 NATIONAL ENERGY SAVINGS

DOE developed the NES model to estimate the total national energy savings using the results from the shipments model, combined with information from the LCC on energy savings. The savings shown in the NES reflect decreased energy losses resulting from the installation of new, more efficient transformer units nationwide, in comparison to a base case with no national standards. Positive values of NES correspond to net energy savings, specifically a decrease in energy consumption after implementation of a standard in comparison to the energy consumption in the base case scenario.

10.2.1 National Energy Savings Overview

DOE calculated the cumulative incremental energy savings from a transformer efficiency standard, relative to a base case scenario of no standard, over the forecast period. It calculated NES for each candidate standard level, in units of quads, for standards that it assumed will be implemented in the year 2016. The NES calculation started with estimates of transformer shipments and stocks (in-service transformers), which are outputs of the shipments model (Chapter 9). DOE then obtained estimates of transformer losses from the LCC analysis (Chapter 8), and calculated the total energy use by the stock of transformers for each year, for both a base case and a standards case. Over time, in the standards case, more efficient transformers gradually replace less efficient ones. Thus, the energy per unit capacity used by the stock of transformers gradually decreases in the standards case relative to the base case. DOE converted energy used by the transformers into the amount of energy consumed at the source of electricity generation (the source energy) with a site-to-source conversion factor. The site-to-source factor accounts for transmission, distribution, and generation losses. For each year analyzed, the difference in source energy use between the base case and the standards scenario is the annual energy savings. DOE summed the annual energy savings from 2016 through 2045 to calculate the total NES for the forecast period.

In calculating the NES, DOE did not assume any trends in transformer name-plate efficiency besides the incremental efficiency improvement indicated by the LCC calculation.

[a] The analysis period for NPV is based on the cumulative operating cost benefits of the last unit shipped (2045 + maximum life -1).

DOE examined proprietary shipments data provided by the transformer industry and found that the data lacked conclusive trends in efficiency improvement. Therefore, DOE felt that future efficiency trends were generally indeterminate and chose to use a fixed baseline efficiency. DOE also assumed that the efficiency of transformers does not degrade over time. This means the annual energy savings can be described in terms of an affected stock (see Equation 10.1), as described in section 9.3.11 in the shipments chapter:

In calculating the NES, DOE did not assume any trends in transformer name-plate efficiency besides the incremental efficiency improvement indicated by the LCC calculation. DOE examined proprietary shipments data provided by the transformer industry and found that the data lacked conclusive trends in efficiency improvement. Therefore, DOE felt that future efficiency trends were generally indeterminate and chose to use fixed baseline efficiency. DOE also assumed that the efficiency of transformers does not degrade over time. This means the annual energy savings can be described in terms of an affected stock (see Equation 10.1), as described in section 9.3.11 in the shipments chapter:

$$AES(y) = (UEC\ Base - UECStd\ ) \times Aff\_Stock(y) \qquad \text{Eq. 10.1}$$

where:

AES(y)	=	the annual energy savings in year y,
UECBase	=	the site unit energy consumption for the base case,
UECStd	=	the site unit energy consumption for the standards case, and
Aff_Stock(y)	=	stock of transformers of all vintages that are operational in year y.

Then, given the annual energy savings, the NES can be calculated as a simple sum:

$$NES = \sum_{y=Std_{year}}^{2045} SiteToSource(y) \times AEC(y) \qquad \text{Eq. 10.2}$$

where:

Std_year	=	the year standards come into effect,
SiteToSource(y)	=	the site-to-source conversion factor in year y, and
AEC	=	the annual energy consumption.

Once the shipments model provides the estimate of the affected stock, the key to the NES calculation is in calculating UECBase and UECStd, using the input from the LCC analysis and including the site-to-source conversion factor. The next section summarizes the inputs necessary for the NES calculation and then presents them individually.

10.2.2 National Energy Savings Inputs

The NES model inputs fall into three broad categories: (1) those that help convert the data from the LCC into data for the equipment classes and transformer size distributions used in the NES; (2) those that help calculate the unit energy consumption; and (3) the site-to-source conversion factor, which enables the calculation of source energy consumption from site energy use. The specific list of NES model inputs is as follows:

1. size scaling of losses and costs;
2. mapping of LCC design line data to equipment classes;
3. root mean square loading;
4. load growth;
5. affected stock;
6. effective date of standard;
7. unit energy consumption; and
8. electricity site-to-source conversion.

10.2.2.1 Size Scaling of Losses and Costs

DOE used a scaling relationship, or equation, to project the economic results from one transformer design line to similar transformers of different sizes. This relationship is a key element in adjusting losses and costs from a representative transformer in the LCC to the distribution of transformer sizes represented in the NES calculation.

As described in the engineering analysis, DOE applied the "0.75 scaling rule" for projecting losses and costs from one design line to transformers of other sizes. In the NES analysis, DOE calculated shipments in terms of installed capacity. It estimated the losses associated with a stock of transformers, and the costs associated with a capacity shipped, by multiplying the relevant capacity by the average losses, or costs, per unit capacity. Before applying the 0.75 scaling rule, DOE calculated the losses and costs per unit of installed capacity within a given engineering design line. Then it calculated an adjustment factor using the 0.75 scaling rule to account for the fact that the representative design line unit used in the engineering analysis is not exactly the "average" transformer size for the set of transformers that the design line represents. This adjustment factor is given by the following equation:

$$AdjFactor = \sum_i [Ship_i \times Cap_i{}^{0.75}] / (Cap_{DL}{}^{0.75} \times \sum_i Ship_i) \qquad \textit{Eq. 10.3}$$

where:

AdjFactor	=	adjustment factor that gives the shipment-weighted losses or costs per transformer when multiplied by the design line losses or costs,
$Ship_i$	=	shipments in the *i*-th size category,
Cap_i	=	the rated capacity for the transformers in the *i*-th size category, and
Cap_{DL}	=	the rated capacity of the representative unit of the design line.

DOE also used the shipment-weighted average size of transformers represented by a particular design line to calculate the average loss per capacity ($AvgLossPerCap_{DL}$), as described in the following equation:

$$AvgLossPerCapDL = LossPerCapDL \times AdjFactor \times CapDL / Capavg \qquad \textit{Eq. 10.4}$$

where:

$LossPerCap_{DL}$	=	the loss, or cost per unit capacity, for the design line unit from the LCC analysis, and
Cap_{avg}	=	the shipment-weighted average size of transformers represented by a particular design line.

Once the losses and costs from the LCC represented the correct size distribution, they needed a further adjustment so that they represented the appropriate equipment classes, as described in the next section.

10.2.2.2 Mapping Life-Cycle Cost Design Line Data to Equipment Classes

The NES and NPV calculations use the LCC calculations as the source of most input data. DOE performed the LCC calculations by design line, whereas any eventual standard would be promulgated by equipment class. As a first step, therefore, the NES calculation aggregates the LCC design line data into equipment classes. This design-line-to-equipment-class aggregation was the process by which DOE took the results from an economic analysis of engineering design lines and combined them to provide estimates of economic impact by equipment class.

To represent the variety of designs in some equipment classes, DOE analyzed up to three different design lines per equipment class. Specifically, equipment class 1 (single-phase, medium-voltage, liquid-immersed transformers) is represented by three design lines, and equipment class 2 (three-phase, medium-voltage, liquid-immersed transformers) is represented by two design lines. DOE did not specifically examine single-phase, medium-voltage dry-type design lines. For single-phase equipment classes 5, 7, and 9, DOE used the appropriate three-phase design lines divided by three. Table 10.2.1 presents the mapping of design line (DL) to equipment class (EC).

Table 10.2.1 Mapping of Design Line to Equipment Class

Equipment Class	BIL	Capacity	Mapping
Liquid-immersed, medium-voltage, single-phase	Any	10-833	DL1 + DL2 + DL3
Liquid-immersed, medium-voltage, three-phase	Any	15-2500	DL4 + DL5
Dry-type, low-voltage, single-phase	≤ 10 kV	15-333	DL6
Dry-type, low-voltage, three-phase	≤ 10 kV	15-1000	DL7+DL8
Dry-type, medium-voltage, single-phase,	20-45 kV	15-833	(DL9 + DL10)/3
Dry-type, medium-voltage, three-phase,	20-45 kV	15-2500	DL9 + DL10
Dry-type, medium-voltage, single-phase,	46-95 kV	15-833	(DL11+DL12)/3
Dry-type, medium-voltage, three-phase,	46-95 kV	15-2500	DL11 + DL12
Dry-type, medium-voltage, single-phase,	> 95 kV	75-833	DL13/3
Dry-type, medium-voltage, three-phase,	> 95 kV	225-2500	DL13

To aggregate losses from more than one design line, DOE took a shipments-capacity weighted average of the per-kilovolt-ampere (kVA) transformer characteristics from the economic analysis of the design lines and applied the average per-capacity values to the estimated capacity shipped for each equipment class. DOE's contractor[1] provided the capacity shipped for each design line (and each equipment class). The LCC analysis provided the economic results for each design line, and DOE used the 0.75 scaling rule to estimate the re-scaled cost and loss estimates for each size category represented by each design line. Equation 10.5 provides the average loss per unit capacity of equipment class (AvgLossPerCapEC), as derived from the average loss per unit capacity for a design line:

$$AvgLossPerCap_{EC} = \sum_{DL}[AvgLossPerCap_{DL} \times MS_{DL}] \Big/ \sum_{DL} MS_{DL} \qquad \textit{Eq. 10.5}$$

where:

$AvgLossPerCap_{DL}$	=	the average loss per unit capacity for the design line, and
MS_{DL}	=	the capacity market share of the design line.

Equation 10.5 sums those design lines that constitute an equipment class.

The $AvgLossPerCap_{EC}$ represents the average loss per unit capacity of the transformer load. For no-load losses, no more adjustment is needed; for load losses, however, the losses at rated load need to be converted to losses at actual loading. The RMS loading is a key factor in estimating load losses at actual loading. The next section describes the RMS loading input.

10.2.2.3 Root Mean Square Loading

Energy losses in transformers follow the RMS load, not the arithmetic average load. DOE calculated the RMS loading as the RMS of the transformer load, divided by the transformer rated capacity, multiplied by the power factor. (As explained in Chapter 6, while DOE's method for analysis can derive results for varying power factors, for the analysis presented here DOE set the power factor to the value of one.) DOE used the average national RMS loading for each design line as calculated in the LCC analysis. These values range between 26.2% and 41.9% for the different design lines.

10.2.2.4 Load Growth

The fractional load growth is the fraction by which the load has increased since a transformer was installed. DOE investigated load growth as a sensitivity. Load growth occurs when new equipment, new appliances, or additional activities increase the energy loads on the circuits served by distribution transformers. Load growth has the impact of increasing the load losses relative to the losses that DOE estimated to have occurred during the first year of installation.

DOE calculated the fractional load growth from an estimated load growth rate that it used as an input to the LCC analysis. There is a maximum load growth, *LGRMax*, which DOE set at 50 percent for liquid-immersed transformers. The 50 percent value represents the approximate amount of growth in load that can occur without overloading the transformer beyond a reasonable point. When overloading does occur, the transformer is assumed to be relocated and installed in a new location with the same initial peak loading as when originally installed.[6] See Institute of Electrical and Electronics Engineers, Inc. (IEEE) Std C57.91-1995[7] for details on permissible overloading of mineral-oil-immersed transformers. Since IEEE does not report data on permissible overloading of dry-type units, DOE used the same values for both liquid-immersed and dry-type transformers. The age of the transformer at which the load switches to initial peak load is given by Equation 10.6:

$$age_{Max} = {ln\ (1 + LGRMax)}\Big/{ln\ (1 + LGR)} \qquad \textit{Eq. 10.6}$$

where:

age_{Max}	=	the maximum age of transformer after which time the load switches to initial peak load (years), and
LGR	=	the annual load growth rate (%).

Thus, the equation for the load growth as a function of the age of the transformer is as follows:

$$LGrwth(age) = (1 - LGR)^{(age)} - 1 \qquad \textit{Eq. 10.7}$$

for age < age_{Max} , and

$$LGrwth(age) = (1 - LGR)^{(age-ageMax)} - 1 \qquad \textit{Eq. 10.8}$$

for age >= age_{Max}

where:

LGrwth (age)	=	the fractional load growth, and
age	=	the age of the transformer (years).

DOE then used the load growth to adjust the RMS loading estimate for the affected stock. The mathematical equation for this adjustment is as follows:

$$LAdjust(y) = \sqrt{\sum_{age=1}^{y-Std\_year}[Stock(y, age) \times (1 + LGrwth(age))^2]\,/Aff\_Stock(y)} \qquad \textit{Eq. 10.9}$$

where *LAdjust(y)* is the load adjustment factor in year *y*. All other variables have been defined in previous equations.

DOE used a load adjustment factor to calculate an adjusted RMS loading that incorporates load growth into the unit energy consumption, as described in section 10.2.2.6.

10.2.2.5 Affected Stock

The affected stock is an output of the shipments model (Chapter 9) and a key input for the NES and NPV calculations. The affected stock represents that portion of the transformer stock that is potentially impacted by a standard. It therefore consists of those transformers in the stock that are purchased in or after the year the standard has taken effect, as described by the following equation:

$$Aff_{Stock(y)} = Ship(y) + \sum_{age=1}^{y-Std_{year}} Stock(age) \qquad \textit{Eq. 10.10}$$

where:

Aff_Stock(y)	=	stock of affected transformers of all vintages that are operational in year *y*,
Ship(y)	=	shipment of new transformers in year *y*,
Std_year	=	year the standard becomes effective, and
Stock(age)	=	age in years of the stock of transformers.

10.2.2.6 Unit Energy Consumption

One of the final quantities DOE calculated for the NES estimate was the unit energy consumption for affected stock. The unit energy consumption multiplied by the capacity shipped and the site-to-source conversion factor equals the annual energy consumption from which DOE derived total NES.

Annual unit energy consumption *(UEC(y))* for affected stock is the annual energy consumption per unit capacity for transformers shipped after the effective date of a standard. DOE calculated the losses per transformer as the sum of no-load losses plus the load losses. It calculated the load losses as the rated load loss times the square of RMS loading, adjusted for load growth. Average energy consumed per unit capacity for affected stock varies from year to year due to load growth effects.

The annual unit energy consumption for affected stock of distribution transformers is given by Equation 10.11:

$$UEC(y) = E_{NL} + E_{LL} \times [RMS \times LAdjust(y)]^2 \qquad \textit{Eq. 10.11}$$

where:

E_{NL}	=	rated no-load losses per kVA capacity,
E_{LL}	=	rated load losses per kVA capacity,
RMS	=	root mean square, and
LAdjust(y)	=	loading adjustment factor for year y.

Once DOE defined the unit energy consumption for affected stock, only one more input was necessary to complete the NES calculation: the site-to-source conversion factor.

10.2.2.7 Electricity Site-to-Source Conversion

The site-to-source conversion factor for electricity is the factor by which site energy (in kilowatt-hours (kWh)) is multiplied to obtain primary (source) energy (in Btu). Since the NES estimates the change in energy use of the resource (e.g., the power plant), this conversion factor is necessary to account for losses in generation, transmission, and distribution. After calculating energy consumption at the site of its use—the installed transformer—DOE multiplied the site energy consumption by the conversion factor to obtain primary energy consumption, expressed in quads. This conversion permitted comparison across (source) fuels by taking into account the heat content of different fuels and the efficiency of different energy conversion processes. The annual conversion factor values are the U.S. averages for electricity generation for both peak and base load. DOE used average heat rates corresponding to base load for no-load losses (or core losses) and average heat rates corresponding to peak load for load losses (or coil losses). It used these different rates because load losses are higher during transformer peak loads while no-load losses occur at all times. DOE obtained these conversion factors using a variant of the NEMS, called NEMS-BT.[a] Table 10.2.2 presents the average annual conversion factors DOE used.

Table 10.2.2 Average Site-to-Source Conversion Factors for No-Load Losses and Load Losses

Year	For No-Load Losses	For Load Losses
2015	1.906	2.582
2016	1.906	2.577
2017	1.900	2.563
2018	1.896	2.555
2019	1.892	2.544
2020	1.885	2.540
2021	1.887	2.545
2022	1.890	2.531
2023	1.888	2.518
2024	1.890	2.503
2025	1.892	2.482
2026	1.890	2.455
2027	1.893	2.437
2028	1.901	2.418
2029	1.891	2.403
2030	1.902	2.396
2031	1.901	2.388
2032	1.907	2.381
2033	1.895	2.375

[a] For more information on NEMS, refer to DOE's EIA documentation. A useful summary is National Energy Modeling System: An Overview 2003.5 DOE/EIA approves use of the name NEMS to describe only an official version of the model without any modification to code or data. Because this analysis entailed some minor code modifications and the model is run under policy scenarios that are variations on DOE/EIA assumptions, the name NEMS-BT refers to the model as used here (BT is DOE's Building Technologies Program, under whose aegis this work was performed).

2034	1.896	2.369
2035	1.904	2.365
2036-2045	1.904	2.365

The conversion factors change over time and account for the displacement of generating sources. The NES spreadsheet model includes the conversion factors for each year of the projection. DOE and stakeholders can examine the effects of alternative assumptions by revising this column of numbers.

The conversion of site energy savings to source energy savings and the summation of energy savings over the forecast period complete the calculations needed to estimate the NES. The next section of the chapter (section 10.3) describes the technical details of the NPV calculation. The results section (section 10.4) presents the NES and NPV results from the national impact spreadsheet.

10.3 NET PRESENT VALUE

DOE estimated the national financial impact on consumers from the imposition of new energy efficiency standards using a national NPV accounting component in the national impact spreadsheet. DOE combined the output of the shipments model with energy savings and financial data from the LCC to calculate an annual stream of costs and benefits resulting from candidate distribution transformer energy efficiency standards. It discounted this time series to the year 2010 and summed the result, yielding the national NPV.

10.3.1 Net Present Value Overview

The NPV is the present value of the incremental economic impact of a candidate standard level. Like the NES, the NPV calculation started with transformer shipments and transformer stocks, estimates of which are outputs from the shipments model. DOE then obtained estimates of transformer first costs, losses, and average marginal electricity costs from the LCC analysis. It calculated the amount spent on transformer purchases and installation, and then calculated the corresponding operating costs by applying the marginal prices to the energy (both energy and electricity system capacity) used by the stock of transformers for each year, for both a base case and a standards case. Over time, in the standards case, more expensive, but more efficient, transformers gradually replace less efficient transformers. Thus, the operating cost per unit capacity used by the stock of transformers gradually decreases in the standards case relative to the base case, while the equipment costs increase.

DOE discounted purchases, expenses, and operating costs for transformers using a simple national average discount factor. The discount factor converts a future expense or benefit to a present value. The difference in present value of all expenses and benefits between the base case and standards scenario is the national NPV impact. DOE calculated the NPV impact from transformers that were purchased between the effective date of the standard and 2045, inclusive, to calculate the total NPV impact from purchases during the forecast period. Mathematically, NPV is the value in the present time of a time series of costs and savings, described by the equation:

$$NPV = PVS - PVC \qquad \textit{Eq. 10.12}$$

where:

PVS	=	the present value of electricity savings, and
PVC	=	the present value of equipment costs including installation.

PVS and *PVC* are determined according to the following expressions:

$$PVS = \sum_{y=Std\_year}^{21053} \left[{}^{OC_{Base}}/_{Cap}(y) \times {}^{OC_{Std}}/_{Cap}(y) \right] \times Aff\_Stock(y) \times Discount\ Factor(y) \qquad \textit{Eq. 10.13}$$

where:

$OC_{Base}/Cap(y)$	=	operating cost per unit capacity of transformer for the base case in year *y*,
Aff_Stock(y)	=	stock of transformers of all vintages that are operational in year *y*,
y	=	the year (from effective date of the trial standard to the year when units purchased in 2045 retire), and
Discount Factor(y)	=	discount factor for the year *y*, defined in Eq. 10.14.

$$Discount\ Factor(y) = {}^{1}/_{(1 + Discount\ Rate)^{(y - reference\ year)}} \qquad \textit{Eq. 10.14}$$

where:

reference year	=	year 2010, and
discount rate	=	the rate of discount as described in section 10.3.2.7.

$$PVC = \sum_{Std\_year}^{2105} \left[{}^{FC_{std}}/_{Cap}(y) - {}^{FC_{Base}}/_{Cap}(y) \right] \times Ship(y) \times DiscountFactor(y) \qquad \textit{Eq. 10.15}$$

where:

$FC_{Std}/Cap\ (y)$	=	first cost of the transformer per unit of capacity for a candidate standard level *Std* in year *y*, (First cost is defined in Eq. 10.16 and described in section 10.3.2.1.)
Std_year	=	the year standards come into effect, and
Ship(y)	=	shipments of transformers in year *y* for the standards case.

DOE calculated NPV using its projections of national expenditures for distribution transformers, including purchase price (equipment and installation price) and operating costs (electricity and maintenance costs). It calculated costs and savings as the difference between a candidate standards case and a base case scenario without national standards. It discounted future costs and savings to the present.

DOE calculated a discount factor from the discount rate and the number of years between the year to which the sum is being discounted (2010) and the year in which the costs and savings occur. The NPV is the sum over time (2016–2104) of the discounted net financial savings. The following sections describe the inputs specific to the NPV calculation.

10.3.2 Net Present Value Inputs

The NPV model inputs include cost inputs, inputs important for detailing electricity capacity costs, and several of the inputs used by the NES calculation. This section provides details on those inputs that have not yet been described as part of the NES and shipments models. The specific list of inputs for the NPV is as follows:

1. first cost;
2. operating cost;
3. peak responsibility factor;
4. initial peak load;
5. electricity price forecast scalar;
6. marginal electricity costs; and
7. discount rate.

10.3.2.1 First Cost

The first cost includes all of the initial costs that are incurred with the installation of a transformer. DOE expresses first cost in terms of cost per unit capacity. Specifically, it defines the first cost of acquiring a transformer with the following equation:

$$FC/Cap = (P + Install)/Cap \qquad \text{Eq. 10.16}$$

where:

FC	=	the first cost,
Cap	=	the rated capacity of the transformer,
P	=	the price of the transformer including shipping and taxes, and
Install	=	the installation cost of the transformer.

In the NPV calculation, these values are obtained from the LCC calculation as the averages for specific design lines. DOE applied an adjustment factor to convert the first cost of a representative design to an estimated average first cost for a distribution of sizes within a particular equipment class. The adjustment incorporates the 0.75 scaling rule and the design-line-to-equipment-class mapping. This adjustment factor is explained in detail in sections 10.2.2.1 and 10.2.2.2. The costs are expressed in units of 2010$ per kVA of rated transformer capacity.

Table 10.3.1 shows the resulting mean first costs per kVA for distribution transformers by CSL and equipment class.

Table 10.3.1 First Cost[a] of Distribution Transformers by Candidate Standard Level and Equipment Class (2010$/kVA)

Equipment Class	Base	CSL 1	CSL 2	CSL 3	CSL 4	CSL 5	CSL 6	CSL 7
Liquid-immersed, medium-voltage, single-phase	82.81	92.32	100.92	109.15	117.68	137.97	144.78	145.01
Liquid-immersed, medium-voltage, three-phase	27.54	29.94	31.40	32.36	33.18	38.60	59.22	59.22
Dry-type, low-voltage, single-phase	63.90	66.64	74.94	81.15	82.92	90.75	101.59	137.04
Dry-type, low-voltage, three-phase	42.99	43.48	46.35	51.57	55.83	66.62	70.64	94.83
Dry-type, medium-voltage, single-phase,	34.39	39.97	43.13	47.20	51.21	70.81	70.81	70.81
Dry-type, medium-voltage, three-phase,	28.76	33.96	35.78	38.82	41.57	58.52	58.52	58.52
Dry-type, medium-voltage, single-phase,	44.88	49.53	54.15	59.53	62.78	75.16	90.25	90.25
Dry-type, medium-voltage, three-phase,	32.18	36.13	39.30	43.59	45.20	51.86	68.99	68.99
Dry-type, medium-voltage, single-phase,	38.54	43.51	49.91	54.23	60.32	79.85	79.85	79.85
Dry-type, medium-voltage, three-phase,	29.81	33.65	38.60	41.94	46.65	61.75	61.75	61.75

10.3.2.2 Operating Cost

Transformer operating cost is the annual cost of transformer losses. Operating costs are a complex, yet essential, part of calculating the national economic impact of a distribution transformer standard. DOE used distinct costs to calculate the value of different types of losses and peak capacity savings. Potential load growth also requires a load growth adjustment factor. Peak loading, peak load coincidence, and average loading require additional factors to characterize load losses. Finally, DOE used an electricity price forecast scalar to characterize future trends in electricity prices consistent with the AEO2010 forecast.

DOE assumed zero incremental maintenance cost in calculating the transformer operating costs. It calculated annual operating costs using the following formula to capture the diversity of potential factors that can affect these costs:

$$OC/Cap = EPFS(y) \times (E_{NL} \times (NLLMCC + 8760 \times NLLMEC) + E_{LL} \times (LAdjust(y))^2 \times (PRF \times PL2 \times LLMCC + 8760 \times RMS2 \times LLMEC))/Cap \qquad \text{Eq. 10.17}$$

where:

OC = the operating cost,

[a] First Cost here includes installation cost.

Cap	=	the rated capacity of the transformer,
EPFS(y)	=	the electricity price forecast scalar for year y,
E_{NL}	=	the no-load losses at rated load,
NLLMCC	=	the no-load loss marginal cost of capacity,
NLLMEC	=	the no-load loss marginal energy cost,
E_{LL}	=	the load losses at rated load,
LAdjust(y)	=	the load growth adjustment factor in year y,
PRF	=	the peak responsibility factor,
PL	=	the initial peak load,
LLMCC	=	the load loss marginal cost of capacity,
RMS	=	the root mean square loading of the transformer, and
LLMEC	=	the load loss marginal energy cost.

DOE expressed the operating costs in units of 2010$ per kVA of rated capacity. As in the NES calculation (see sections 10.2.2.1 and 10.2.2.2), DOE also applied an adjustment factor to incorporate the 0.75 scaling rule to E_{NL} and E_{LL}, to convert from design line data to equipment class estimates.

The following four sections explain the inputs of the operating cost equation that are not explained in the NES section.

10.3.2.3 Peak Responsibility Factor

The transformer peak responsibility factor (PRF) is the fraction of the transformer peak that is coincident with the system peak, calculated by taking the square of the ratio of the transformer load at the time of the customer peak load to the transformer peak load. In combination with the initial peak loading, the PRF is necessary for estimating the capacity cost impacts of transformer load losses. DOE used the average PRF from the hourly and monthly load analysis for the liquid-immersed and dry-type transformers, respectively, as reported in the LCC analysis. Table 10.3.2 presents the PRFs used in the analysis for ten equipment classes.

Table 10.3.2 Peak Responsibility Factors by Equipment Class

	EC 1	EC 2	EC 3	EC 4	EC 5	EC 6	EC 7	EC 8	EC 9	EC 10
PRF	0.48	0.48	0.36	0.36	0.46	0.54	0.51	0.56	0.56	0.56

10.3.2.4 Initial Peak Load

The initial peak loading is the annual per-unit peak load on the transformer during the first year of operation. This factor, in combination with the PRF, is necessary for calculating capacity cost impacts from transformer load losses. The initial peak load is estimated as a percentage of the rated peak load of the transformer. The Institute of Electrical and Electronics Engineers Draft Guide for Distribution Transformer Loss Evaluation[6] defines a similar, but different, measure of peak transformer loading called an “Equivalent Annual Peak Load” that accounts for changes in peak load over the life of the transformer. Rather than use the equivalent annual peak load method, DOE characterized a range of possible initial peak loads by defining a distribution of initial peak loads. Chapter 6, sections 6.2.3.3 and 6.3.3.3, provide further description of DOE's method. Table 10.3.3 presents the initial peak loadings used in the analysis for the 10 equipment classes.

Table 10.3.3 Initial Peak Loading by Product Class

	EC 1	EC 2	EC 3	EC 4	EC 5	EC 6	EC 7	EC 8	EC 9	EC 10
Initial Peak Loading	0.88	0.88	0.80	0.79	0.85	0.85	0.81	0.80	0.80	0.80

10.3.2.5 Electricity Price Forecast Scalar

The electricity price forecast scalar converts current electricity costs into forecasted costs for the period 2010–2105. The electricity price forecast scalar is the ratio of the unit cost of electricity in real dollars in a given year to the real cost of electricity in the year 2010. DOE used AEO2010[4] forecasts to obtain the electricity price forecast scalar. For the period beyond 2035, DOE used the EIA real dollar price trend from 2025 to 2035 to extrapolate the electricity price scalar.

10.3.2.6 Marginal Electricity Costs

The characterization of four distinct marginal electricity costs was necessary to calculate the operating costs of transformers and the financial impact of transformer efficiency standards. The four types of marginal costs are: no-load loss marginal capacity cost (NLLMCC), load loss marginal capacity cost (LLMCC), no-load loss marginal energy cost (NLLMEC), and load loss marginal energy cost (LLMEC). In an electricity system, there are both energy costs and capacity costs. Depending on the load shape of a particular load, the average value of capacity costs and energy costs are different. Because no-load losses and load losses have distinct load shapes, and because different customers have different load shapes, costs vary both by loss type and by the equipment class of the transformer. DOE therefore used distinct marginal energy and capacity costs for no-load losses and load losses for each transformer equipment class. No transformer size scaling is necessary for the marginal costs, although DOE needed to apply the design-line-to-equipment-class mapping described in section 10.2.2.2 to convert the design line output from the LCC to equipment class information for the NPV calculation. DOE calculated capacity costs in units of 2008$/kW/year, and energy costs in units of 2008$/kWh. Table 10.3.4 summarizes the four marginal costs for the 10 equipment classes.

Table 10.3.4 Marginal Energy and Demand Costs by Equipment Class

Marginal Energy Cost by Equipment Class ($/kWh)										
	EC 1	**EC 2**	**EC 3**	**EC 4**	**EC 5**	**EC 6**	**EC 7**	**EC 8**	**EC 9**	**EC 10**
NLL	0.067	0.049	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060
LL	0.073	0.054	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059
Marginal Demand Cost by Equipment Class ($/kW/year)										
	EC 1	**EC 2**	**EC 3**	**EC 4**	**EC 5**	**EC 6**	**EC 7**	**EC 8**	**EC 9**	**EC 10**
NLL	498.59	498.59	142.62	142.62	142.62	142.62	142.62	142.62	142.62	142.62
LL	197.66	197.66	104.25	104.68	104.25	104.25	104.25	104.25	104.25	104.25

10.3.2.7 Discount Rate

The discount rate expresses the time value of money and is the final input to the NPV calculation. DOE used real discount rates of 3 percent and 7 percent, as established by the U.S. Office of Management and Budget (OMB) guidelines on regulatory analysis.[8] The discount rates DOE used in the LCC are distinct from those it used in the NPV calculations, in that the NPV discount rates represent the societal rate of return on capital, whereas LCC discount rates reflect the owner cost of capital and the financial environment of electric utilities and commercial and industrial entities.

10.4 RESULTS

10.4.1 National Energy Savings and Net Present Value from Trial Standard Levels

Table 10.4.1 presents the NES and NPV results from the NES spreadsheet model for CSL 1 through CSL 7. It should be reiterated that, currently, the NES spreadsheet model uses discrete point values rather than a distribution of values for all inputs.

Table 10.4.1 Summary of Cumulative National Energy Savings (2016–2045) and Net Present Value (2016–2104) Impact

Analysis	Discount Rate (%)	Candidate Standard Level						
		1	2	3	4	5	6	7
Liquid-Immersed								
Cumulative Source Savings 2045 (Quads)		0.63	1.39	1.70	1.94	2.29	2.52	2.53
Net Present Value (B 2010$)	3	5.31	14.08	15.36	15.28	8.94	-3.49	-3.57
	7	0.46	2.43	1.81	0.76	-4.10	-11.69	-11.73
Dry-Type								
Cumulative Source Savings 2045 (Quads)		0.27	0.65	1.02	1.33	1.84	2.11	2.40
Net Present Value (B 2010$)	3	2.17	4.92	6.62	8.13	8.60	8.25	2.89
	7	0.56	1.14	1.20	1.33	0.47	-0.31	-3.86

10.4.1.2 Liquid-Immersed Results

Figure 10.4.1 illustrates the typical pattern of primary energy savings and costs resulting from standards for liquid-immersed transformers over time. The figure shows the nature of net savings for all seven CSLs relative to the base case. In this figure, the levels are ordered from lowest to highest energy savings.

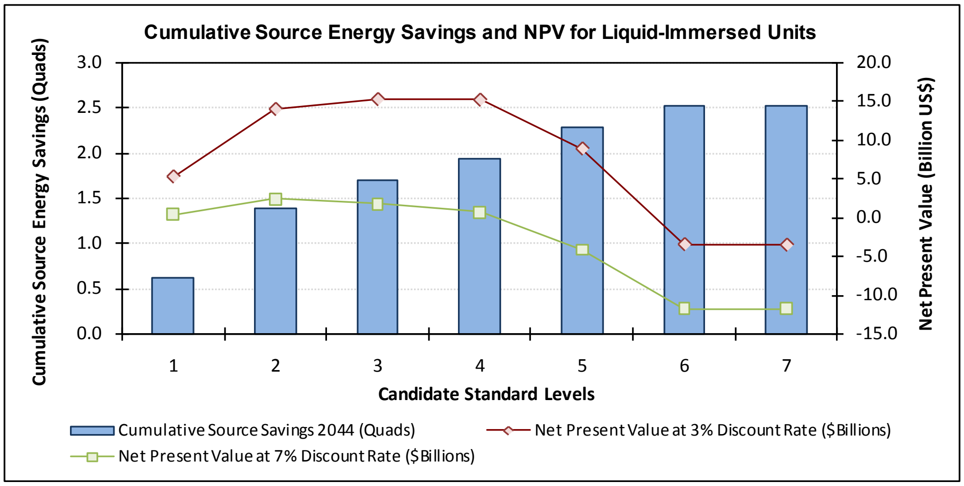

Figure 10.4.1 Liquid-Immersed Distribution Transformers: National Energy Savings and Net Present Value Impacts

10.4.1.3 Dry-Type Results

Figure 10.4.2 shows the typical pattern of national savings and costs resulting from standards for dry-type transformers over time. Again, the figure shows the nature of net savings for six dry-type transformer CSLs relative to the base case.

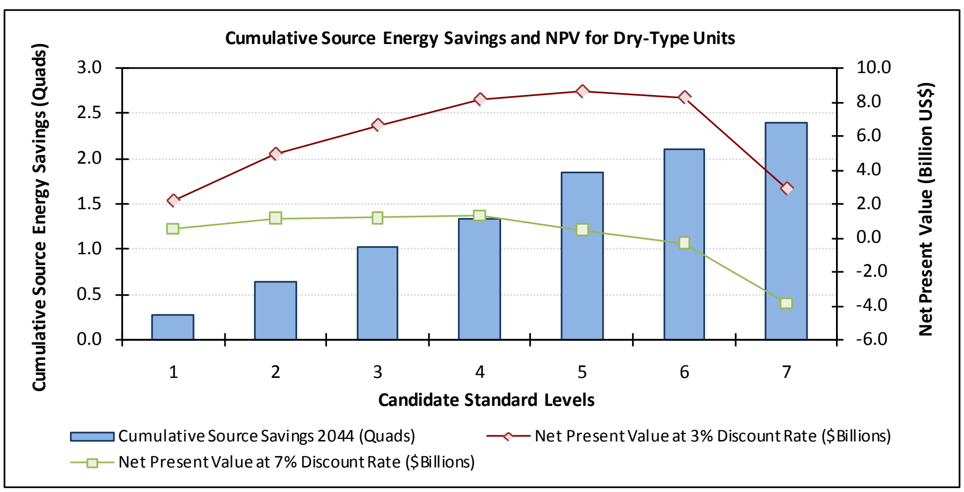

Figure 10.4.2 Dry-Type Distribution Transformers: National Energy Savings and Net Present Value Impacts

The national impact spreadsheet is available as an Excel file on the DOE website: www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html. Instructions for using the spreadsheet are in Appendix 10A of this TSD.

REFERENCES

1. Hopkinson, P. *Distribution Transformer Market Shipment Estimates for 2009*. (Washington DC., 2010).

2. Bureau of Economic Analysis Industry Economic Accounts Information Guide. Annual Industry Accounts. Gross Domestic Product (GDP) by Industry. (2005).

3. U.S. Department of Energy-Energy Information Administration *Annual Energy Review 2009, Chapter 8: Electricity, Table 8.9 Electricity End Use, 1949-2009*. (U.S. Department of Energy: Washington DC, 2010).

4. U.S. Department of Energy – Energy Information Administration *Annual Energy Outlook 2010: With Projections Through 2035*. (U.S. Department of Energy: Washington DC, 2010).

5. Energy Information Administration - Office of Integrated Analysis and Forecasting *The National Energy Modeling System*. (U.S. Department of Energy: Washington DC, 2009).at <http://www.eia.doe.gov/oiaf/aeo/overview/>

6. Institute of Electrical and Electronics Engineers Inc. Draft Guide for Distribution Transformer Loss Evaluation. (2001).

7. Institute of Electrical and Electronic Engineers Inc. Guide for Loading Mineral Oil-Immersed Transformers. (1995).

8. U.S. Office of Management and Budget Circular A-4: Regulatory Analysis. (2003).